3.6 AIR QUALITY

The proposed power plant would produce sufficient emissions to qualify as a major emissions source and therefore falls under the Oregon Department of Environmental Quality's (ODEQ) Prevention of Significant Deterioration (PSD) rules. Modeling of the power plant's emissions by the project proponent indicates that they would be within acceptable limits compared with state and federal emission standards, and the power plant would not by itself have a significant effect on local and regional ambient air quality. Potential cumulative air quality impacts with other reasonably foreseeable projects in the region are addressed in Section 3.6.3. Phase 2 of BPA's Regional Air Quality Modeling Study (described in Section 3.6.3) will provide additional information for the final EIS regarding project-specific impacts to visibility for the proposed project.

The combustion of natural gas at the proposed power plant would add slightly to the worldwide production of carbon dioxide (CO_2), a greenhouse gas believed to contribute to global warming. The project's CO_2 emissions are about 3 percent of existing CO_2 emissions in Oregon.

3.6.1 Affected Environment

3.6.1.1 Regulatory Procedure for Evaluating Air Quality Impacts from a Proposed Project

The proposed power plant site is located in an area currently designated as unclassified or in attainment of all state and national Ambient Air Quality Standards (AAQS). The goal of the air quality analysis is to demonstrate that a proposed power plant will not significantly deteriorate air quality and that the new emissions, when added to existing sources, will not cause ambient pollution levels to exceed established standards for health and safety. To establish that a new project will comply with the state and Federal regulations, a project developer must follow a series of steps designed to screen out insignificant sources in order to identify and study those emissions with the potential to cause a significant impact. In Oregon, this process is known as ODEQ's New Source Review (NSR) Program. A flow chart of the NSR process is presented in Figure 3.6.1. The process consists of: (1) determining if the project qualifies as a major source and if the *quantity* of emissions is significant; (2) performing a screening analysis to determine if the *impacts* of emissions are significant; and, if necessary, (3) performing detailed modeling of background sources and the significant proposed impacts and comparing them to the standards. This process is followed for each regulated pollutant. After the process has been completed and the project has demonstrated that it meets ODEQ standards and that the best available control technology (BACT) has been included in the design, an Air Contaminant Discharge Permit (ACDP) can be issued, allowing the project to be constructed.

Air quality impacts of a new source of emissions are determined by four interrelated factors; 1) climate and meteorology; 2) existing air pollution sources and current air quality in the area; 3) the site configuration and surrounding terrain; and 4) the source. ODEQ has developed a set of procedures that determines a project's air quality impacts, demonstrates compliance with all regulations, and ensures protection of human health and the environment.

The proposed power plant, as a major new source of air emissions, would be subject to NSR and must develop and submit a PSD application to ODEQ. The PSD application must demonstrate that emissions from the facility would result in ambient concentrations of air pollutants that are less than state and Federal AAQS for criteria and toxic air pollutants. Furthermore, the facility would not be allowed to contribute to ambient air quality concentrations greater than the AAQS. Concentrations resulting from power plant emissions must not exceed the allowable PSD increments.

3.6.1.2 Air Quality Factors in the Existing Environment

Climate and Meteorology: Eastern Oregon has a dry continental climate (low humidity), with large variations in temperature from winter to summer. Daily temperatures in January average a little over zero °C (32 °F), and a typical winter includes only a few days with minimum temperatures below –18 °C (zero °F). July temperatures average around 21 °C (70 °F), and a typical summer has only a few days with maximum temperatures in excess of 38 °C (100 °F). Very little precipitation falls in the area. Annual precipitation in the project area is slightly less than 23 centimeters (nine inches). Most of this precipitation is due to winter storms crossing the region. Consequently, the peak precipitation months are November, December, and January. Average annual snowfall is about 25 centimeters (10 inches) with over 75 percent of this amount occurring from December through March. There is very little rain during the summer months. Summer rain is usually associated with a thunderstorm and can be heavy for short periods.

There are two predominant 'bimodal' wind directions in the immediate vicinity of the proposed power plant, aligning along the Columbia River Valley, which has a channeling effect on the flow of air near the river. This river valley effect combines with prevailing westerly flow in the region to produce prevailing winds from the west-southwest. The other most common is caused by cold air flowing down the river valley during the night and early morning hours, producing winds from the east-northeast.

Existing Air Pollution Sources and Current Air Quality: Air quality in an area is defined by ambient ground-level concentrations of specific pollutants. Acceptable air quality exists when the pollutant concentrations are below the state and federal standards. The air quality in an area can be determined either by direct measurement or by modeling. Since current monitoring data are often unavailable, modeling is commonly used as an acceptable method for evaluating air quality. Limited ambient air quality data are available from PGE's Coyote Springs, Unit 1 Project at the Port of Morrow. These pre-construction monitoring data were collected from August 1994 through August 1995. No other monitoring data are available for the project vicinity. The maximum short term and annual average observed concentrations are presented in Table 3.6.1. These data indicate that existing ambient concentrations are well below the State and Federal Ambient Air Quality Standards (AAQS) shown in Table 3.6.1.

Ambient Air Quality Standards: The Clean Air Act of 1970 (CAA) mandated that the EPA establish ambient ceilings for certain pollutants based on the identifiable effects that pollutants may have on the public health and welfare. Subsequently, EPA promulgated regulations that establish national AAQS for a number of pollutants. These pollutants, called criteria pollutants, include sulfur dioxide (SO_2), particulate matter less than 10 microns in diameter (PM_{10}), nitrogen dioxide (NO_2), carbon monoxide (CO), photochemical oxidants such as ozone (O_3), and lead (Pb). The Federal PM_{10} standard replaces an earlier standard for total suspended particulate matter (TSP); however, ODEQ has retained the TSP standard. The national and Oregon AAQS are shown in Table 3.6.2.

In July 1997, EPA revised the standards for ozone and particulate matter. The revised standards are shown in Table 3.6.3. EPA also revised the form (but not the level) of PM_{10} 24-hour and annual standards. The revised standards for ozone, PM_{10} and $PM_{2.5}$ were promulgated by EPA in September 1997. However, EPA has estimated that it would take three to five years to implement the standards fully, and it is expected that $PM_{2.5}$ attainment and nonattainment area designations would take at least three to five years, with an additional three to seven years needed to implement control measures. For the interim, PM_{10} standards may be used as a surrogate for $PM_{2.5}$ standards in meeting NSR requirements until technical difficulties involving measurement are resolved (EPA, 1997). Although promulgated, the new standards are not currently enforced by EPA and the states.[1]

Attainment Status: Section 107 of the 1977 Clean Air Act Amendments required both the EPA and individual states to evaluate the attainment of the national AAQS. Areas not meeting national AAQS are designated as nonattainment areas. Areas that lack sufficient data to be used in the determination of attainment status are unclassified but are treated as attainment areas until designated otherwise. The classification of an area is made on a pollutant-specific basis. The proposed power plant site is located in Umatilla County, Oregon; air quality throughout the nearby region is currently designated as unclassified or

[1] A 1999 federal court ruling temporarily blocked implementation of the new 8-hour ozone and 24-hour $PM_{2.5}$ standards. The U.S. Supreme Court subsequently overturned the U.S. Federal Appeals Court ruling in February 2001, but directed EPA to revise its implementation policy before implementing the ozone standard. EPA and the states are currently working to develop ozone implementation plans. Before implementing the $PM_{2.5}$ standard, EPA and the states are required to collect and analyze 3 years of ambient data, which will not be completed until 2002 or later. In the meantime, these new standards are not implemented.

in attainment of each state and national AAQS. Portions of Yakima County, Washington, approximately 60 kilometers (37 miles) northwest of Hermiston, and the Wallula area, approximately 40 kilometers (25 miles) northeast of Hermiston, are designated as PM_{10} nonattainment areas. The U.S. Environmental Protection Agency recently re-designated the Wallula area as serious nonattainment.[2] These represent the closest nonattainment areas to the power plant site.

Toxic Air Pollutants: In addition to criteria pollutants, ODEQ also regulates emissions of toxic air contaminants. No data exist on the ambient concentrations of air toxics in the project area.

Site Configuration and Surrounding Terrain: The configuration of nearby buildings and facilities and the topography of the land within about a 16-kilometer (10-mile) radius of an emission source can influence the dispersion of exhaust plumes and affect ground-level pollutant concentrations. The terrain immediately surrounding the power plant site is generally level. Foothills rise around the site in all directions about 3.2 to 14.5 kilometers (2.0 to 9.0 miles) out from the site. Hills or mountains higher than the stacks are important in the air quality analysis because the exhaust plume can be affected by the elevated terrain before the plume has a chance to disperse. Therefore, the topography is explicitly accounted for in the air quality modeling performed for the proposed power plant.

Buildings near a stack can create wind turbulence. If stack exhaust gases are emitted into this turbulence, the plume can become mixed with ground-level air within a very short distance of the stack, resulting in high pollutant concentrations. This condition is called “downwash” and occurs only when the stack height is too short for the plant configuration (Schulman and Hanna 1986, Schulman et al. 1985). Good Engineering Practice was followed in the design of the turbine stacks for the proposed power plant, taking into account the size of the nearby buildings in calculating the height of the stacks (EPA 1985). This resulted in a stack height of 65 meters (213 feet) for the proposed power plant. Extensive engineering experience and observation have shown that a stack built to Good Engineering Practice guidelines will not cause downwash.

3.6.2 Environmental Consequences and Mitigation Measures

Potential impacts on air quality, such as compliance with ambient air quality standards, regional haze, nitrogen and sulfur deposition, associated with construction and operation of the proposed power plant include:

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[2] Although the serious nonattainment designation is being enforced, ambient data indicate that concentrations do not currently exceed state/federal standards. EPA’s redesignation of the Wallula area to serious nonattainment status was based on historic ambient monitoring data that may have been unduly influenced by blowing fugitive dust. Based on more recent monitoring data that shows no violations, Washington Ecology is working with EPA to redesignate the area to attainment. The redesignation process may take one or more years to complete.

- Emissions of pollutants into the atmosphere as a byproduct of natural gas combustion.

- Emissions of very low levels of pollutants in steam resulting from pollutants in cooling water.

- Production of a visible steam plume from the cooling towers.

- Fog and ice on local roadways and railroads caused by steam from the cooling towers.

- Contributions to the world's production of greenhouse gases that may cause global warming.

- Production of construction machinery exhaust emissions and fugitive particulate matter during construction.

<u>Impact 3.6.1 Emissions from the Combustion Turbines and Auxiliary Emergency Equipment</u>

<u>Assessment of Impact</u> Each combustion turbine in the power plant would produce extremely hot exhaust gases from the combustion of natural gas. Much of the heat in these gases would be used to produce steam in the heat recovery steam generator for additional power generation. Under certain operating conditions, additional natural gas is combusted in the inlet to the heat recovery steam generator. This is called supplemental duct firing and is used to generate additional steam during periods of high electrical demand. The heat recovery steam generators reduce the exhaust gas temperature to about 91 °C (195 °F). The exhaust gas from each combustion turbine and heat recovery steam generator then flows to a separate stack. The chemical composition and physical parameters (i.e., temperature and volumetric flow) of the exhaust gas vary with the ambient temperature and load conditions. This is because the ambient temperature affects the fuel usage, power output, and combustion conditions.

To maintain operational flexibility, the power plant may be required to shut-down and subsequently restart one or both of the turbines. Pollutant mass emission rates during start-up can exceed normal operational emission rates because control equipment has not yet reached operating temperatures.

The start-ups are classified as hot, warm, and cold, based on the duration of the preceding shut-down period. A hot start is defined as a turbine start-up following a shutdown period of up to 8 hours. A warm start is preceded by a shutdown period of between 8 and 48 hours, while a cold start is preceded by shutdown periods in excess of 48 hours. The time required to bring the power block to full rated capacity is highly dependent on a complex series of variables and varies substantially with turbine and plant design.

In order to determine the maximum potential emissions, the proposed power plant has been analyzed for a number of operating modes and ambient temperatures: Base-load (100 percent) with and without supplementary duct firing and part load (80 and 60 percent, both without supplementary duct firing), and –18, 12, and 45 °C (zero, 53, and 113 °F).

The maximum predicted emissions of regulated pollutants from the combustion turbine at the proposed power plant are listed in Table 3.6.4. Expected emissions due to testing of emergency equipment (firewater pump engine) are also included in this table.

All predicted emission rates presented in Table 3.6.4 represent emissions with emission controls included in the power plant design. As described previously, the proposed power plant includes a continuous emissions monitoring system (CEMS) for each unit. CEMS will be provided for NO_x and CO. The CEMS allows operators to ensure that pollutant emission rates do not exceed the permitted rates. Additionally, each CEMS is equipped with alarms to alert the operators and regulators when emission rates approach the permitted limits. Most importantly, the CEMS provides the operator with valuable information on the performance of the power plant so that facility efficiency is optimized and pollutant emissions are minimized.

The air quality analysis that has been performed for the proposed power plant follows.

New Source Performance Standards: The EPA has promulgated a set of national emission standards that apply to specific categories of new sources. The New Source Performance Standards (NSPS) for boilers with heat input greater than 264 gigjoules/hr (250 MMBtu/hr) (40 CFR 60, Subpart Da) sets forth maximum allowable emissions for NO_x and SO_2. This applies to the duct burners. The NSPS for gas turbines with heat input greater than 10.72 gigajoules/hr (10.16 MMBtu/hr) (40 CFR 60, Subpart GG) sets forth maximum allowable emissions for NO_x and SO_2. The standards applicable to the proposed power plant are as follows.

- The NO_x emission standard applicable to each of the proposed duct burners is 0.09 kg NO_x/gigajoule (0.20 lb NO_x/MMBtu). Uncontrolled emissions are estimated at 0.04 kg NO_x/gigajoule (0.10 lb NO_x/MMBtu), less than the NSPS of 0.09 kg NO_x/gigajoule (0.20 lb NO_x/MMBtu). Reduction of NO_x emissions by the SCR system would further reduce the emissions.

- The NO_x emission standard applicable to each of the proposed turbines is 114 parts per million by volume (ppmv) corrected to 15 percent oxygen on a dry basis. The proposed power plant's estimated NO_x emissions of 2.5 ppmv are well below the NSPS of 114 ppmv.

- For SO_2, the NSPS limits the sulfur content of the fuel to 0.8 percent (weight basis). The natural gas proposed for the power plant has a sulfur content of 0.0024 percent by weight. This concentration is far below the NSPS of 0.8 percent.

Applicability Determination: There are three basic criteria in determining whether PSD rules apply to a project. The first and primary criterion is whether the proposed power plant's emissions would be great enough to be a "major" source. The second criterion is whether the new source would be located in an area that has been classified attainment or nonattainment. The third criterion is whether the pollutants would be emitted in "significant" amounts.

The proposed plant site would not be located within 10 kilometers (6 miles) of any Class I areas, which could also trigger PSD. There are, however, several Class I areas that require analysis due to their proximity to the project (within 200 kilometers [124 miles]). The closest Class I area would be the Eagle Cap Wilderness Area, located about 140 kilometers (87 miles) east of Hermiston. The ODEQ and United States Forest Service (USFS) Federal Land Manager (FLM) also require that the Columbia River Gorge National Scenic Area (CRGNSA) be treated like a Class I Wilderness Area although it is not classified as such. The CRGNSA is located approximately 117 kilometers (73 miles) west of the power plant site.

Major Source: A new source is major if it has the potential to emit any regulated pollutant in amounts equal to or exceeding specified major source thresholds (91 metric tons [100 tons] per year for gas turbine generators over 268 gigajoules [254 MMBtu]). The proposed power plant exceeds these major source thresholds for NO_x, CO, and PM_{10}.

Attainment Status of Air Quality Control Region: New projects located in nonattainment areas must apply for a Nonattainment Area permit. Those in attainment areas complete a PSD review. Since the Hermiston area is considered in attainment for criteria pollutants, the proposed power plant meets the second criterion for PSD review.

Significant Emissions: Significant emissions are defined as those that equal or exceed the Oregon Significant Emission Rates. To determine if the power plant has significant emissions, the annual emission rates in Table 3.6.4 are compared to the significant emission rates for each pollutant, also shown in the table. The proposed power plant's potential to emit exceeds major stationary source PSD thresholds and significant emission levels, as defined in OAR 340.200.0020, for NO_x, CO, PM_{10}, and VOC.

Air Quality Impact Analysis: The proposed power plant meets the criteria for PSD review. Therefore, air quality modeling is required to determine maximum ground-level concentrations caused by project emissions.

Dispersion modeling was performed by the project proponent using the EPA's Industrial Source Complex Short-Term 3 (ISCST3) model (Version 00101). The turbine stacks and firewater pump were modeled as separate point sources. Additional parameters required for modeling point sources include source location, stack base elevation, stack height, stack inner diameter, stack gas exit velocity, and stack gas exit temperature. The modeling simulates the behavior of the exhaust plumes from the stacks. The plume would initially rise before leveling off and drifting downwind, because it is hotter than the atmosphere (Briggs 1971).

The ambient air quality modeling was performed using one year of onsite meteorological data. The onsite meteorological data were collected starting January 1, 1994 and were collected to PSD standards. These data were previously processed and used in support of the ACDP permit application for the Hermiston Generating Project.

A total of 33 computer simulations for 'worst-case' operating scenarios (for each pollutant and averaging period) were performed to estimate ground-level concentrations resulting from the power plant's emissions. Dispersion modeling results, shown in Table 3.6.5, indicate that air quality impacts resulting from the operation of the facility will be less than the Oregon DEQ Significant Air Quality Impact (SAQI) levels. The SAQI levels are equivalent in nature to the Significant Impact Levels (SILs) in the federal Prevention of Significant Deterioration rules. The SAQIs are a small fraction (0.2 – 6%) of the ambient air quality standards. Facilities that have air quality impacts less than the SAQI levels are considered to have no significant adverse impact on air quality and are not required to include emissions from other nearby sources in air quality analyses for permitting. Note that models used for this analysis are conservative (i.e., likely to overstate actual emissions).

Emissions of criteria pollutants (NO_x, CO, PM_{10}, VOC, and SO_2) to the atmosphere would occur from the combustion of natural gas in the combustion turbines and duct burners, and the combustion of diesel fuel in the firewater pump. The project proponent's modeling analysis has been reviewed and approved by Oregon DEQ modeling staff and shows that the maximum predicted concentrations are below the SAQIs for for all criteria pollutants. Thus, following federal and state air quality rules, the proposed power plant would not be expected to have a significant adverse impact on air quality in the project area. Although some areas as near as 40 kilometers (25 miles) from the power plant site are designated nonattainment for PM_{10}, the power plant would not have a significant impact on this area because PM_{10} impacts from the power plant would be below SAQIs. Phase 2 of BPA's Regional Air Quality Modeling Study (described in Section 3.6.3) will provide additional information for the final EIS regarding project-specific impacts to visibility for the proposed project.

Mitigation Measures included in the Proposed Project

Efficient air pollutant emission control measures are incorporated into the design of the power plant to reduce emissions of criteria pollutants. For example, the project design incorporates the use of clean natural gas to minimize emissions of PM_{10} and SO_2. The design also includes the use of special catalysts to control NO_X, CO and VOC to very low levels. The Oregon DEQ has preliminarily determined that these control measures constitute Best Available Control Technology. Oregon DEQ reviewed other available control technologies in making that determination. No other available cost effective control technologies would achieve greater reductions in emissions.

Other Possible Control Measures

If a project is found to have significant adverse impacts, the project proponent may consider additional mitigation measures from other sources to partially offset the project's emissions and impacts. To be effective, such mitigation measures must target undercontrolled sources of groups or similar undercontrolled sources that may make substantial contributions to air pollution. On that basis, the following three examples of potential mitigation measures for regional haze impacts are evaluated below:

1) Diesel freight train locomotives that travel generally east-west through the project region along the Columbia River currently emit NOx, PM10 and SO2. These freight trains typically travel long distances, including interstate travel. The locomotive engines might be retrofitted to burn cleaner fuels such as natural gas to reduce emissions of all three pollutants, but this measure is considered not feasible for the following reasons:
   - This technology would require major and very costly engine modifications, or the purchase of new locomotives and has not been demonstrated to be economically feasible for large diesel locomotives to date.
   - Technology for safely transferring and storing sufficient quantities of fuel onboard for long-distance hauling would need to be developed and demonstrated.
   - An extensive infrastructure along the rail system would be required for refueling the trains, potentially in multiple states. None of this infrastructure exists today and would be very costly to develop for this project.

2) A program could potentially be implemented to retrofit or retire aging vehicles that are used in the project region. Retrofitting aging non-catalyst vehicles with catalysts to reduce local regional nitrogen oxide emissions is not cost effective in most cases because catalyst retrofits also require extensive engine modifications. The pre-catalyst (generally pre-1974) automobiles do not have the necessary computer systems and engine controls in place. Catalyst and engine retrofits are cost-prohibitive for these aging vehicles according to interviews that have been conducted with automotive

repair shops. In addition, remaining vehicles of this age have approached or exceeded their normal life span. Retrofitting such vehicles would not produce lasting emission reductions since most of these cars would naturally be replaced with newer cleaner cars during the life of the proposed power plant.

3) A program to replace conventional (i.e., pre-1986) wood stoves with certified (i.e., post-1986) stoves in the project region could reduce existing regional NOx and PM10 emissions. For example Oregon DEQ (Mr. Steve Aalbers, July 27, 2001) has estimated that approximately 77% of homes in Hood River County use wood burning stoves, one third of which are conventional stoves (numbering approximately 2590 units). These conventional stoves in Hood River County produce an estimated 500,000 pounds (250 tons) of PM10 annually according to DEQ. Converting all of these stoves to certified non-catalytic stoves would reduce their PM10 emissions by about 36% to approximately 320,000 pounds/year (160 tons/year). The replacement cost would range between $600 and $3000 per stove unit, according to DEQ. Thus, the net decrease would be about 180,000 pounds/year (90tons/year), at a cost of $1.55-7.76 million. The related cost per ton of emission reduction ($17,000–86,000 per ton) is considered cost prohibitive. This is more than double the range that is considered cost-effective by Oregon DEQ Best Available Control Technology (Mr. Doug Welch, Oregon DEQ, July 31, 2001).

Impact 3.6.2 Emissions from the Cooling Towers

Assessment of Impact Columbia River water used in the power plant's operation would contain trace amounts of impurities, such as dioxins, furans, and radionuclides (including natural and manmade isotopes of carbon, hydrogen, phosphorous, iron, cobalt, cesium, strontium, and uranium). Dioxins and furans strongly associate with solid particles in the river water, some of which would be removed by filtration before the water is used in power plant processes. Radionuclides can also be associated with solid particles, or can be dissolved in the water. The cooling towers would be the dominant pathway for process water contact with air at the power plant although drift would be reduced by the installation of high efficiency drift eliminators.

Most of the water entering the cooling towers evaporates and may carry the more volatile impurities with it. However, it is expected that most of the unfiltered impurities will remain dissolved or bound to particles in the liquid water that exits the cooling tower as blowdown into the power plant reclaimed water stream. Approximately 1.9 liters per minute (0.5 gallon per minute) of liquid water exit the cooling towers as small droplets called "drift." Drift is predominantly river water that has been concentrated 10 times by evaporation within the cooling tower, so 1.9 liters per minute (0.5 gallon per minute) of drift will contain impurities from about 19 liters per minute (five gallons per minute) of river water. At this rate, the project's total contribution of drift-borne river water impurities will not substantially increase the existing atmospheric loading of river mist from sources such as wind/wave interaction on the Columbia River and dam spillways. Based on the above analysis, cooling tower drift emissions are not expected to pose a significant health or environmental risk.

Recommended Mitigation Measures None.

Impact 3.6.3 Fogging and Icing

Assessment of Impact Cooling towers remove unusable excess heat from the power plant by evaporating water in cooling towers. The moist air emitted from the cooling towers often condenses to form a visible white plume of steam. Generally, the steam plumes disappear by evaporating in a short distance. However, the steam plume can remain visible for long distances under certain meteorological conditions.

Occasionally, the steam plume will settle down to the ground near the power plant site. This is known as cooling tower-induced fogging. When conditions are right for fogging and the temperature is below freezing, icing can occur. Potential occurrences of cooling tower-induced fogging and icing were modeled using a standard model and three years of surface meteorological data from the Umatilla Chemical Depot.

Icing Impact: Based on the modeling, there are no predicted occurrences of cooling tower-induced icing on nearby roads.

Fogging Impact: The results of the modeling analysis show that a total of 2.5 hours of offsite ground-level fogging are predicted from the three years of meteorological data. The extent of the ground level fogging was limited to 1600 meters (5,249 feet) from the center of the cooling tower along an east northeasterly plume heading.

The risk of fogging and icing as a result of the proposed project would be reduced by the installation of high efficiency drift eliminators. Also, the orientation of the cooling towers was adjusted during the design process to minimize the impacts of fogging and icing.

Recommended Mitigation Measures No measures beyond those included in the proposed project are recommended..

Impact 3.6.4 Effects of Emissions on Visibility and other Air Quality Related Values

Assessment of Impact Emissions from the proposed power plant must be assessed to ensure that ecosystems and pristine vistas in Wilderness Areas and National Parks are not deteriorated by pollutants in the air. Air Quality Related Values (AQRVs), including visibility, were analyzed for the Class I areas within 200 kilometers (124 miles) of the Project site. Table 3.6.6 lists the Class I areas and their distances from the project site.

To assess visibility beyond 50 kilometers (31 miles) from a proposed project, the USFS requires that the analysis be based on an assessment of the impact on "regional haze" at the closest boundary of the Class I area. The "regional haze" assessment described below was performed with Level I screening methods outlined in the Interagency Workgroup on Air Quality Modeling (IWAQM) (EPA, 1993), as amended by guidance from the ODEQ.

Visibility is usually characterized by either visual range (VR) (the greatest distance that a large dark object can be seen) or by the light-extinction coefficient (b) (the attenuation of light per unit distance due to scattering and absorption by gases and particles in the atmosphere). The basis of the regional haze assessment is a calculation of the change in the light extinction coefficient. A percent change of less than 5% is considered insignificant by the Federal Land Manager's AQRV Workgroup (FLAG) Phase I Report (FLAG, 2000).

The peak modeled change in the background extinction coefficient would occur at the Mount Adams Wilderness Area. The calculated maximum percent change in the extinction coefficient is 4.89% and would occur one day per year or less. This predicted change is less than the 5% significance level for Class I areas. The modeled change in extinction coefficient for the Class I areas are presented in Table 3.6.7.

Estimates of nitrate and sulfate deposition were determined to assess the proposed power plant's effect on vegetation, aquatic, and biological resources/ecosystems at the nearby wilderness areas. The estimates were calculated from modeled concentrations of NO_x and SO_2. The estimates are compared to suggested 'no-injury levels' for both total nitrogen deposition and sulfur deposition as given in the USFS Guidelines for Evaluating Air Pollution Impacts on Class I Wilderness Areas in the Pacific Northwest (1992). Nitrogen deposition can be expected to have no effect if levels are below 3 kg/ha-yr (3 lb/acre-yr) for coniferous forests, shrubs, and herbaceous plants and 5 kg/ha-yr (5 lb/acre-yr) for hardwood forests. The maximum predicted deposition of nitrogen as nitrate for all Class I Areas in the region, 0.14 kg/ha-yr (0.2 lb/acre-yr) at Goat Rocks, is between 2.8 and 4.7 percent of the no injury levels. Maximum nitrate deposition will be less at other Class I Areas. The suggested no-injury level for sulfur deposition is 5 kg/ha-yr (5 lb/acre-yr). The maximum predicted sulfur deposition rate is 0.02 kg/ha-yr (0.02 kg/ha-yr), or approximately 0.4 percent of the no-injury level. The results of this conservative modeling analysis indicate that the maximum deposition values should not present significant ecosystem impacts.

Detailed calculations and evaluations of the AQRV analyses are provided in the ACDP application. The results of these very conservative analyses indicate that the proposed power plant would not cause AQRV or visibility impacts to any Class I areas (UGC 2001).

Recommended Mitigation Measures No measures beyond those included in the proposed project are recommended.

Impact 3.6.5 Global Warming

Assessment of Impact The proposed power plant would emit CO_2 during both the construction and operation phases. If increased atmospheric CO_2 is leading to a global warming effect, then the proposed power plant would contribute to CO_2 emissions and to global warming.

Although CO_2 emissions are not currently regulated by any ambient concentration standard, in order to receive a site certificate from the Energy Facility Siting Council (EFSC), the Umatilla Generating Company, L.P. must demonstrate compliance with the State of Oregon's carbon dioxide emissions standard for energy facilities. Specifically, EFSC must find "that the net carbon dioxide emissions rate of the proposed facility does not exceed 0.306 kilogram (0.675 pounds) of carbon dioxide per kilowatt hour of net electric power output, with carbon dioxide emissions and net electric power output measured on a new and clean basis" (OAR 345-024-0550). For carbon dioxide emissions from duct burning, EFSC must find that the incremental emissions do not exceed 0.32 kilogram (0.70 pound) of carbon dioxide per kilowatt hour of net electric power output, also measured on a new and clean basis. The proposed power plant's gross carbon dioxide emissions rate would be approximately 0.4 kilogram (0.8 pounds) of carbon dioxide per kilowatt hour for net power output at base load. With duct burning, the gross carbon dioxide emissions rate would be approximately 0.5 kilogram (1.0 pounds) of carbon dioxide per kilowatt hour using calculation methods specified by EFSC.

Umatilla Generating Company, L.P. has agreed to comply with the State's carbon dioxide emissions standard by providing offset funds to The Climate Trust (formerly, The Oregon Climate Trust) as allowed by Energy Facility Siting Council regulations. The offset fund rate is \$0.57 million per ton of carbon dioxide in excess of the standard for net electric power output with and without duct burning, and amounts to \$5.28 million for this project. The project will produce approximately 1.9 million metric tons of CO_2 annually. This will add approximately 3% to existing CO_2 emissions in Oregon (61.6 million metric tons per year estimated by Mr. Sam Sadler of Oregon Office of Energy July 12, 2001). Project emissions represent less than one millionth of existing CO_2 emissions in the United States. The Climate Trust must use the offset funds to achieve real reductions in atmospheric gases believed to contribute to global warming.

Recommended Mitigation Measures No measures beyond those included in the proposed project are recommended.

Impact 3.6.6 Construction Impacts

Assessment of Impact The two biggest sources of air pollution during the construction phase of the proposed project are equipment exhaust emissions and fugitive particulate matter emissions. Short term emissions from construction sites are exempt from any air quality permitting requirements in Oregon.

Exhaust Emissions

Construction-related equipment exhaust emissions would result from operation of heavy equipment and from construction worker's vehicles used to travel to and from the construction site.

The amount of pollutants emitted from construction vehicles and equipment and construction worker commute traffic would be small compared to total vehicular emissions in the region. To reduce combustion pollutants, idling construction equipment would be shut down where feasible and low NO_x emission tune-ups on equipment operating on site for more than 60 days would be performed.

Dust Emissions

Fugitive particulate matter ("dust") emissions are generated by actions such as grading, vehicle travel on disturbed ground, and wind erosion. Site excavation and grading activities would disturb onsite soils and would result in loose dirt and silt which could become airborne when subject to a moderate or strong wind and/or when moved during construction-related activities. Some of these airborne particles (typically less than 40 μm in diameter) might be carried off the power plant site.

Since fugitive emissions are emitted at or close to ground level, maximum impacts due to these emissions typically occur within or very close to the property line, with rapidly decreasing impacts beyond this point. To reduce fugitive dust emissions caused by construction activities, Umatilla Generating Company, L.P. would take the following precautions:

- Unpaved construction areas would be watered a minimum of twice daily during construction in dry weather. Trucks hauling dirt would be covered or wet down. Frequency of watering exposed soil surfaces would be increased when blowing dust is visible.

- Stored construction materials that could be a source of dust would be covered.

- Vehicle speeds on unpaved project areas would be limited to 32 kilometers (20 miles) per hour.

Recommended Mitigation Measures No measures beyond those included in the proposed project are recommended.

3.6.3 Cumulative Impacts

The proposed project will use advanced combined-cycle gas turbine technology, clean-burning natural gas, and high efficiency air emission control technology. Resultant air emissions will meet or exceed current Best Available Control Technology (BACT) requirements[3].

Existing air quality in the project region is better than state and federal standards, with the possible exception of PM_{10} in the Wallula, Washington vicinity, as discussed above. Air quality modeling by the project proponent (described above) indicates that the project alone will not cause existing good air quality to deteriorate significantly, nor will the project's emissions limit future industrial growth. Conservative EPA-approved air quality models indicate that the project's impacts will be below Oregon's very stringent "significant air quality impact levels" (SAQIs) and also below the less stringent federal significance levels that apply in other parts of the nation, such as Washington and Idaho.[4]

This EIS will consider regional cumulative effects of existing sources, this project and other proposed turbine projects. Two new electric power plants have been approved and are currently under construction in the vicinity. One is east of Hermiston (Hermiston Power Partners) and the other is located at the Port of Morrow (Coyote Springs Unit 2). In response to the current power emergency in the Pacific Northwest and other areas of the western U.S., as of July 1, 2001, six additional electric power projects are proposed in the project region, and are under regulatory review. If all proposed power projects are built, the cumulative impact on air quality, visibility and atmospheric nitrate deposition may be significant. Recognizing this situation, BPA recently initiated a detailed modeling study of cumulative air quality and visibility impacts on the Columbia River Gorge and northwest Class I areas. BPA's Regional Air Quality Modeling Study[5] will provide clarifying information about the effects of these proposed electric power projects. The stated study objective is to analyze and disclose pertinent air quality and visibility impacts on sensitive areas from the combined emissions of 45 proposed gas-fired power plants, representing more than 24,000 MW of new generation capacity in Washington, the northern half of Oregon and the Idaho Panhandle. The study will focus on:

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[3] Emissions levels proposed for the project are equivalent to current Lowest Available Emission Rate (LAER) requirements that apply elsewhere in areas of poor air quality (i.e., non-attainment areas).

[4] Air quality impact analysis results are summarized in EIS Section 3.6.2 and further details are documented in the project's February 15, 2001 PSD/ACDP Permit Application that was submitted to the Oregon Department of Environmental Quality. Air quality significance levels are located at OAR 340-200-0020 (117), WAC 173-400-141, and 40 CFR 51.165(b)(2).

[5] 'Regional Air Quality Modeling Study', Bonneville Power Administration, 7/2001. Study can be found at http://www.efw.bpa.gov/cgi-bin/PSA/NEPA/SUMMARIES/air2.

- Effects of PM_{10}, NO_x and SO_2 emissions on regional pollutant concentrations and compliance with the National Ambient Air Quality Standards.

- Effect of power plant emissions on PSD Class I and Class II increments.

- Visibility degradation in the Class I areas.

- Nitrogen and sulfur deposition in the Class I areas.

- Estimated CO_2 emissions from proposed power plants.

The study is being conducted in two phases. Phase I is a regional simulation of proposed power plant sources that identifies areas and sources that exceed significance criteria. Phase II will consist of a separate evaluation of each power plant's contribution to visibility impacts, and is expected to be completed by December 2001. The results of each phase will be public information.

Communication with the Oregon DEQ Pendelton Office indicates that proposed growth of major stationary air pollution sources in the project area (as indicated by air quality permit applications and pre-filing meetings with applicants) is limited to electric power projects. Thus, BPA's regional air quality modeling study addresses the dominant proposed sources of cumulative impact in the area.

The BPA study's Phase I modeling has recently been completed. Of all the parameters evaluated in the study[6], visibility was the only criteria consistently exceeded in Phase I. Assuming that all of the study's 45 proposed power projects are built and operated simultaneously at peak load, modeled regional haze from particulate, sulfur oxide and nitrogen oxide emissions was found to affect all but 2 of the regions' sensitive areas[7]. The operating assumptions used for Phase I modeling are likely to over-estimate impacts. BPA anticipates that only a portion of these plants will likely be constructed, and not all projects would operate at peak load continuously.[8] Phase II of the study will address the specific impacts to visibility for this proposed project. That information will be available in the final EIS.

[6] Other study criteria include: National Ambient Air Quality Standards, New Source Review/Prevention of Significant Deterioration (NSR/PSD) increment consumption, PSD/NSR Significant Impact Levels, and nitrogen and sulfur deposition.
[7] Sensitive areas include NW Class I areas, wilderness areas and the Columbia River Gorge Scenic Area.
[8] A more detailed overview of the modeling approach and presentation of the preliminary Phase I results can be found at http://www.efw.bpa.gov/cgi-bin/PSA/NEPA/ SUMMARIES/air2.

Table 3.6.1:
Ambient Data at Port of Morrow

Pollutant	3-hour	24-hour	Annual
NO_x	–	–	1 ppb
SO_2	21 ppb	10 ppb	1 ppb
PM_{10} (1st-high)	–	105 g/m^3	20 g/m^3
(2nd-high)	–	81 g/m^3	–

Note: ppb = parts per billion by volume; g/m^3 = micrograms per cubic meter

Table 3.6.2:
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	Oregon Standards(2)	National Standards(1) Primary(2,3)	National Standards(1) Secondary(2,4)
Ozone	8-hour	0.08 ppm (157 μg/m^3)	0.08 ppm (157 μg/m^3)	Same
	1-hour	None	0.12 ppm (235 μg/m^3)	Same
Carbon monoxide	8-hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	Same
	1-hour	35 ppm (40 mg/m^3)	35 ppm (40 mg/m^3)	Same
Nitrogen dioxide	Annual average	0.053 ppm (100 μg/m^3)	0.053 ppm (100 μg/m^3)	Same
Sulfur dioxide	Annual average	0.02 ppm	0.03 ppm (80 μg/m^3)	None
	24-hour	0.10 ppm	0.14 ppm (365 μg/m^3)	None
	3-hour	1,300 μg/m^3 (0.5 ppm)	None	0.5 ppm (1,300 μg/m^3)
	1-hour	None	None	None
PM_{10}	Annual	50 μg/m^3	50 μg/m^3	Same
	24-hour	150 μg/m^3	150 μg/m^3	Same
$PM_{2.5}$	Annual	15 μg/m^3	15 μg/m^3	Same
	24-hour	65 μg/m^3	65 μg/m^3	Same
TSP	Annual	60 μg/m^3	None	None
	24-hour	150 μg/m^3	None	None
Lead	Quarterly	1.5 μg/m^3	1.5 μg/m^3	Same

μg/m^3 = Micrograms per cubic meter. mg/m^3 = Milligrams per cubic meter.

1 Standards, other than ozone and those based on annual averages or annual arithmetic means, are not to be exceeded more than once a year. The ozone standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than one.

2 Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based on a reference temperature of 25°C and a reference pressure of 760 mm of mercury. All measurements of air quality are to be corrected to a reference temperature of 25°C and a reference pressure of 760 mm of mercury (1,013.2 millibar); ppm in this table refers to parts per million by volume, or micromoles of pollutant per mole of gas.

3 National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health. Each state must attain the primary standards no later than three years after that state's implementation plan is approved by the Environmental Protection Agency.

4 National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant. Each state must attain the secondary standards within a "reasonable time" after implementation plan is approved by the EPA.

Table 3.6.3:
Summary of July 1997 Revised Federal Air Quality Standards

Pollutant	Averaging Period	Primary Standard	Secondary Standard
Ozone (O_3), parts per million (ppm)	8-hour	0.08	Same
($PM_{2.5}$), micrograms per cubic meter (ug/m^3)	24-hour	65	Same
	Annual	15	Same

Table 3.6.4:
Maximum Predicted Emission Concentrations and Rates

	NO_x	CO	VOC	PM_{10} [(1)]	SO_2
Stack Concentration (ppmvd @ 15% O_2) [(2)]	2.5	10	5.6	N/A	0.5
Per CTG lb/hr [(3)]	20.2	49.2	15.4	24	4.91
Total (2xCTG) ton/yr. [(4)]	196	433	140	184	37.3
Firewater Pump lb/hr [(5)]	2.6	0.54	0.23	0.06	0.19
Firewater Pump ton/yr. [(6)]	$6.8x10^{-2}$	$1.4x10^{-2}$	$6.0x10^{-3}$	$1.6x10^{-3}$	$2.5x10^{-3}$
Total Annual Emissions (tpy)	196	433	140	184	37.3
'Major Source' Significant Emission Rates (tpy)	40	100	40	15	40

1 All particulates are assumed to be PM_{10}.
2 ppmvd = parts per million by volume at dry conditions
3 Hourly emissions per turbine; values based on the maximum emissions under any non-startup operating scenario for each of the turbine alternatives
4 Worst case (on a pollutant basis) of two GE Frame 7FB combustion turbines, 100% load at 53° F (Source: preliminary facility engineering data); SO_2 emissions based on a maximum natural gas sulfur content of 0.75 gr S/100 scf and a minimum fuel heat content of 995 Btu (HHV)/scf. All operations assumed for 8,760 hours/year. The NO_x, CO and VOC emission estimates also include 4,000 hours of duct firing and 200 hot starts, 40 warm, and 10 cold starts per turbine annually. PM_{10} and SO_2 emissions estimates are based on 4,000 hours of duct firing and 4,760 hours at 100% load per turbine.
5 SO_2 emissions based on a diesel fuel sulfur content of 0.1% S by weight.
6 Based on 52 hours of non-emergency use per year.

Table 3.6.5:
Umatilla Air Quality Impact Modeling Results

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$) [1]	Oregon Significant Air Quality Impact Levels ($\mu g/m^3$)
NO_2	Annual	0.18	1.0
CO	Maximum 1-hour	398	2,000
	Maximum 8-hour	33.4	500
PM_{10} [2]	Maximum 24-hour	0.96	1.0
	Annual	0.10	0.2
SO_2 [2]	Maximum 3-hour	13.7	25
	Maximum 24-hour	0.34	5
	Annual	0.02	1.0

[1] Calculated impacts are based on conservative air quality models and assumptions and may over-predict actual impacts.

[2] The maximum modeled 24-hour PM_{10} impact is associated with reduced load operations and occurs in elevated terrain approximately 7.2 kilometers to the southeast of the proposed project. Annual PM_{10} impact occurs in low elevation terrain approximately 5.3 kilometers northeast of the proposed project. Short-term 3- and 24-hour SO_2 impacts are due to occasional maintenance operation of the diesel fueled firewater pump.

Table 3.6.6:
Class I Wilderness Areas within 200 km of Power Plant Site

Class I Wilderness Area	Distance from Power Plant Site (km)
Eagle Cap Mountains	134
Strawberry Mountains	164
Columbia River Gorge National Scenic Area [1]	117
Mt. Hood	178
Mt. Adams	159
Goat Rocks	166

[1] The CRGNSA is not a Federally protected Class I Wilderness Area; however, the ODEQ and FLM have requested a Class I visibility analysis be performed.

Table 3.6.7:
Maximum Change In Class I Wilderness Area Extinction Coefficients

Class I Wilderness Area	Change in Extinction Coefficient (%)
CRGNSA	2.72
Eagle Cap	3.72
Goat Rocks	4.71
Mt. Adams	4.89
Mt. Hood	3.73
Strawberry Mtn.	3.05

Note: These maximum modeled visibility impacts would occur one day per year or less.